Status of Advanced Coal-Fired Power Generation Technology Development in the U.S.

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ABSTRACT

The U. S. Department of Energy (DOE) is working with private industry to develop highly advanced coal-fired power generation systems that will have significantly higher thermal efficiency, superior environmental performance, and a lower cost of electricity than current coal-fired power plants. The goal of the DOE advanced power generation program is to develop the systems to provide 55-60% plant thermal efficiency and to reduce the emissions of sulfur dioxide, nitrogen oxides, and particulates to the level of less than one tenth of the current Federal standards of New Source Performance Standards. Emissions of carbon dioxide, a greenhouse gas, will also be reduced by up to 50% and the cost of electricity will be 10-20% lower than the cost of today's plant.

Advanced systems under development include low emission boiler systems (LEBS), high performance power systems (HIPPS), integrated gasification combined cycles (IGCC), and pressurized fluidized bed combustion (PFBC). These systems will achieve the program goal through the use of advanced components/subsystems and an integrated design approach. Substantial advancements have been made in the subsystem improvement. These power systems rely on advanced environmental control technology as part of the plant.

This paper reviews the technical achievements made to date in the development of these advanced coal-fired power generation technologies, considers further improvements, and discusses its impact on the industry/environment.

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I. INTRODUCTION

Coal-fired power plants provided 31% of all the electricity generated worldwide in 1995 and this percentage is expected to increase to 41% by 2015 as the world's population grows [1]. In the United States, coal is, by far, the most plentiful fossil energy resource, producing more than half the electricity needed in the country. Coal is estimated to last five hundred years at the present rate of use.

The U.S. Department of Energy (DOE) has the goals to use coal more cleanly, more economically, and more efficiently. Highly advanced coal-fired power generation systems are being developed for the future. These systems will provide 52-55% plant thermal efficiency (based on coal's higher heating value) and will emit sulfur dioxide, nitrogen oxides, and particulates at levels less than the current U.S. Federal New Source Performance Standards. The efficiency of today's typical plant is 33-35% (HHV). By increasing the efficiency, carbon dioxide emissions will also be reduced, while the cost of electricity will be 10-15% lower than the cost of today's plant. Performance goals of the advanced power systems are listed in Table 1.

TABLE 1. Performance Goals of Advanced Power Systems

	Conventional Pulverized Coal-Fired Plant	Low Emission Boiler System (LEBS)	High Performance Power Systems (HIPPS)	Integrated Gasification Combined Cycle (IGCC)	Pressurized Fluidized Bed Combustion (PFBC)
Emissions, g/GJ (lb/10^6Btu)					
SO_2	520 (1.2)	43 (0.1)	43 (0.1)	9 (0.02)	43 (0.1)
NO_x	260 (0.6)	43 (0.1)	26 (0.06)	43 (0.1)	43 (0.1)
Particulate	13 (0.03)	4 (0.01)	1.3 (0.003)	4 (0.01)	4 (0.01)
CO_2	baseline	17-22% lower	26-52% lower	20-48% lower	20-48% lower
Solids/liquids products	baseline	useable by-products	useable by-products	useable by-products	useable by-products
Efficiency (net, based on coal HHV), %	33 - 35	42 - 45	47 - 55	42-52	42-52
Cost of Electricity	baseline	10% lower	15% lower	10% lower	10-15% lower
Commercialization	baseline	2001	2006	2015	2010

The advanced power systems include low emission boiler systems, high performance power systems (indirectly fired cycles), pressurized fluidized bed combustion, and integrated gasification combined cycles. Significant improvements are being made in emissions, thermal efficiency, and cost of electricity in the coal-fired plants.

This paper reviews the technical achievements made in developing these advanced coal-fired power systems and discusses current research activities.

A. LOW EMISSION BOILER SYSTEMS (LEBS)

Among all of the advanced coal-fired power systems, LEBS is the most probable near term technology for commercial readiness in 2001. The LEBS program was initiated in 1992 by awarding three industry teams [2]. The program has four phases. Phase I, completed in 1994, included technical and economic evaluations of candidate plant subsystems, a systems analysis of the entire power plant, and the preliminary design of a commercial-scale, 400 MWe LEBS plant. In Phase II three industry teams continued engineering analysis and modeling activities and conducting experimental testing of plant subsystems at scales of approximately 3-10 MWe. Phase III produced the site-specific designs for proof-of-concept (POC) test facilities, 10-80 MWe in size, and updated commercial plant designs and economics based on Phase II results. At the end of Phase III in 1997, DOE selected one team, DB Riley, Inc., to continue on to Phase IV, which includes detailed design, construction, and operation of a 80 MWe POC facility at Elkhart, Illinois. Figure 1 shows the Riley concept of a commercial generating unit design.

The notable technical advances made in LEBS are the low NOx, U-fired, slagging combustion system and the regenerable flue gas cleanup system employing copper oxide sorbents.

Low NOx, U-fired, Slagging Combustion System Slagging combustors produce granulated slag, which has a specific volume approximately one-third that of flyash and is essentially inert in leaching characteristic tests. The 1996 data from the American Coal Ash Association indicated that 93.3% of boiler slag is used as blasting grit/roofing granules, whereas only 27.4% of flyash is used mainly for cement or concrete mixes. Slagging combustors are also better suited for certain types of difficult-to-burn fuel than dry systems. There are over 50 commercial operating U-fired, slagging combustors, but NOx emissions from these units are high, typically 340-770 g/GJ (0.8-1.8 lb/10^6 Btu) from the high operating temperatures. With the Riley low NOx burners (CCV II), air staging, and coal reburning employed at a 30 MWt U-fired test facility at the DB Riley Research Center, NOx emissions were under 86 g/GJ (0.2 lb/10^6 Btu). This U-fired test facility was used to evaluate both high-sulfur Illinois coal and medium sulfur Appalachian coal [3].

Steam Cycle To improve the plant thermal efficiency, the LEBS commercial generating unit design uses a supercritical steam cycle with main steam conditions at a pressure of 31 MPa and a temperature of 594°C (4500 psia/1,100°F), and two reheats, each at 594°C (1,100°F). The supercritical steam cycle will raise thermal efficiency to 42-45% from the current 33-35% industry average. Today, the conventional plant is operating at subcritical steam conditions of 16.5 MPa/538°C (2400 psia /1000 °F), and one reheat at 538°C (1000°F).

The first coal-fired supercritical cycle began operation in 1957 in the U.S. Currently, there are approximately 160 supercritical units, of which 116 are coal-fired. With the exception of the Eddystone Unit 1 (325-MWe) of Philadelphia Electric Company operating at 34.5 MPa/ 655°C/565°C/565°C (5000 psi/1210°F/1050°F/1050°F) and the Philo Unit 6 (125-MWe) of American Electric Power operating at 31 MPA/621°C/565°C/565°C (4500 psi/1150°F/1050°F/ 1050°F), all are designed for steam conditions of a nominal 24.1 MPa (3500 psi) and 565°C (1050°F). Other countries, including Denmark, Germany, Italy, the Netherlands, England, Japan, South Korea, the former Soviet Union, and China, also have operating supercritical plants with thermal efficiencies in the 35-40% range (HHV). These units operate at 24.1-31.0 MPa (3500-4500 psia) and 537-565°C (1000-1050°F).

With advances in materials and boiler design, the efficiency of steam cycles can be improved to 45% (HHV) with main and reheat temperatures of 704°C (1300°F), and to 47% (HHV) with temperatures of 815°C (1500°F) (see Figure 2). Materials research is being conducted to accommodate the high temperature operation.

Copper Oxide Process Riley, along with team member ThermoPower Corporation, is evaluating a moving-bed copper oxide process for removing both SO_2 and NOx from the flue gas [4]. In the current design, flue gas at near 400°C (750°F) flows across a moving bed of sorbent which contains copper oxide impregnated on an alumina substrate. The SO_2 reacts with the copper oxide to form copper sulfate. The sulfated sorbent is regenerated at a temperature of 430-455°C (800-850°F) using natural gas as the reducing agent, forming copper and evolving an off-gas with a high concentration of SO_2 that can be converted to elemental sulfur, sulfuric acid, or fertilizer. In the flue gas stream, copper is reoxidized to copper oxide to be used again.

NOx is also removed from the flue gas because copper sulfate acts as a catalyst for the reduction of NOx using ammonia. Recently, a 1 MWt moving bed copper oxide pilot plant has been constructed and tested at the Illinois Coal Development Park in Carbondale, Illinois. Test results showed 96-99.8% of SO_2 removal and over 99% of NOx removal from the flue gas.

LEBS Proof-of-Concept Plant The proposed LEBS POC plant is a new 80 MWe plant to be located at the Turris Coal Mine near Springfield, Illinois [5]. This POC plant is a test unit for the 400 MWe commercial generating unit design. It will include the Riley low NOx, U-fired slagging unit and a 10 MWe slip stream, copper oxide test module. Because of the size, the plant will have a subcritical steam cycle with a conventional wet scrubber for SO_2 emission control. After the test program is completed, the plant is to operate as an independent power producer and serve as a showcase for LEBS technology. Cost of the POC plant will be $127 million, with DOE providing $34 million.

B. HIGH PERFORMANCE POWER SYSTEMS (HIPPS)

HIPPS is an indirectly fired cycle using both gas and steam turbines. Compressed and heated air is used as a working fluid in the gas turbine. In a HIPPS cycle (see Figure 3), air is heated in a coal-fired high-temperature air furnace (HITAF) and, if necessary, natural gas or coal-derived fuel could be fired into the clean, hot air exiting the HITAF to raise the temperature. The air is expanded in the turbine, producing more than half of the total power output. Heat recovered from the turbine exhaust and from the HITAF flue gas is used to raise steam for the steam turbine. A portion of the turbine exhaust air is used for preheating combustion air. As expected, the HIPPS cycle efficiency will increase as gas turbine inlet temperatures increase (see Figure 4). At the nominal inlet temperature of 1260°C (2300°F), the efficiency is 47%, but it will gradually increase to 49% at 1371°C (2500°F).

The HIPPS program consists of three phases. Phase I, initiated in 1992, focused on the analysis of various configurations of indirectly-fired cycles and technical assessments of alternative plant subsystems and components. Phase II, now underway, involves the development and testing of plant subsystems, refinement and updating of the HIPPS commercial plant design, and the engineering design of a HIPPS prototype plant.

Currently, two industry teams are developing different versions of HIPPS. These two teams are United Technologies Research Center (UTRC) and Foster Wheeler Development Corporation (FWDC).

United Technologies Research Center The UTRC design is similar to that shown in Figure 3. The key component is HITAF that extracts heat from the coal combustion with a radiative air heater and a convective air heater connected in series [6]. The turbine air is heated primarily by radiation to a panel wall and then to three air-carrying tubes located behind the panel wall. The ceramic panel wall protects the tubes from contact with corrosive coal combustion products.

Testing of a radiant air heater panel has been conducted at the University of North Dakota Energy and Environmental Research Center. This panel, originally designed to heat air to 982°C (1800°F), has run with an outlet air temperature exceeding 1094°C (2000°F) for over 1000 hours. These tests confirm the air heater operability and suggest that the air heater design may be capable of operation at temperatures substantially beyond 1094°C. The current state of the art for air heaters was about 760 °C (1400 °F). This UTRC system has the potential to achieve an overall efficiency of 55%.

Foster Wheeler Development Corporation The FWDC is developing a HIPPS that uses a pyrolyzer to convert coal into fuel gas and char. Sorbent is added to the pyrolyzer to capture sulfur to avoid sulfur corrosion in the turbine [7]. After exiting the pyrolyzer, the fuel gas is cooled and then sent to the gas-turbine combustor. The char is burned in a HITAF, where steam is raised for the steam turbine cycle and air is heated for the gas turbine cycle. Air for the gas turbine is heated to 760°C (1400°F) in tubes in the HITAF. Clean fuel gas from the pyrolyzer is fired in the gas turbine combustor. The resulting gas at 1288°C (2350°F) enters the first stage of the gas turbine. Expansion of the air in the turbine produces approximately half of the power output of the system. A portion of the vitiated air from the gas turbine is utilized as combustion air in the HITAF while the remaining portion goes through a heat recovery steam generator (HRSG) before being discharged in the stack. Steam at 580°C (1075°F) and 18 MPa (2615 psi) is produced and sent to the steam turbine, which generates the other half of the power obtained from this system.

C. PRESSURIZED FLUIDIZED BED COMBUSTION (PFBC)

In the mid-1970s, the U.S. experienced serious energy crises by two oil embargoes. Because of these crises, the government began exploring many new technology projects that held the promise of using coal, the most abundant resource, to produce electricity. In a fluidized bed combustor (FBC), coal is fed with a sorbent, limestone, to reduce sulfur from the coal. Sulfur released as SO_2 is captured by the sorbent and removed with the ash. The advantages of FBC compared to the conventional PC-fired plants include: 1) easier siting of the plant due to its relatively small size, and 2) fuel flexibility of burning a wide range of coals and wastes such as tires and municipal and animal wastes.

FBC can be operated in bubbling, circulating, or transport reactor modes. And FBC can be either atmospheric (AFBC) or pressurized (PFBC). Operation in a pressurized mode reduces the plant size and increases the plant efficiency using both steam and gas turbines as a combined cycle configuration.

First-generation PFBC is approaching commercialization in the U.S. and abroad. A 70-MWe unit at the Tidd plant in Brilliant, Ohio, was built and operated under the DOE Clean Coal Technology program. This plant is one of five worldwide large-scale plants. The Tidd plant is a bubbling fluidized-bed combustion process operating at 12 atm (175 psi) with a bed temperature of 900°C (1650°F) [8]. The test results indicated that 90% sulfur removal was achieved with a calcium-to-sulfur ratio of 1.1 and NOx emissions were 64-142 g/GJ (0.15-0.33 lb/10^6 Btu). Heat rate was 10,280 Btu/kWh, or 33.2% efficiency, because of the small-scale retrofit application.

Second-generation PFBC integrates the combustor with a pyrolyzer to fuel a gas turbine (topping cycle), the waste heat from which is used to generate steam for a steam turbine (bottoming cycle) (see Figure 5). The inlet temperature of gas turbine will be 1094°C (2000°F). Foster Wheeler's PFBC technology integrated with Westinghouse's hot gas filter and power generation technologies will be demonstrated at the 157 MWe Lakeland's McIntosh Power Station, Unit 4B, in Lakeland, Florida. Negotiations are near completion between DOE and the City of Lakeland, Department of Electric & Water Utilities. With the increase in gas turbine inlet temperature, over 50% efficiency is possible for the combined cycle.

High-Temperature, High-Pressure Particulate Control To reduce the thermal penalty of cooling gas for cleanup, the high-temperature, high-pressure filters are being developed. These filters are also applicable as a hot gas cleanup component in an IGCC system. Filters for the IGCC system operate at 538-650°C (1000-1200°F), whereas filters being developed for the PFBC operate at the higher temperatures, 650-815°C (1200-1500°F) [9].

Tidd Station slipstream testing was conducted to assess the readiness and economic viability of high-temperature and high-pressure particulate filter systems. The system provided by Westinghouse Electric Corporation consists of a three-cluster filter element, incorporating 384, 1.5-meter (5 ft) long alumina-mullite and clay bonded silicon carbide candle filters. The Westinghouse filter system has been demonstrated 5854 hours, processing approximately 208 m^3/min (7,360 acfm) gas from the 70-MWe Tidd PFBC.

Also, a smaller filter system was installed on the Foster Wheeler pilot scale PFBC facility located in Karhula, Finland, for additional testing. This 10-MWt system holds 128 candle filters in a single cluster arrangement. The purpose of this testing was to find the effects of filter materials, coal and sorbent types on filter performance. Initial tests of clay bonded silicon carbide filter elements at 843°C (1550°F) showed that they are susceptible to elongation by creep at this temperature. Manufacturers then reformulated the materials to improve the creep resistance.

Oxidation of other silicon carbide-based filter elements has been observed at Karhula. Novel filter elements have been fabricated using fiber reinforced ceramic composite technology. One filter under development is fabricated by infiltration of a braided ceramic fiber preform with a silicon carbide coating.

Exposure of this material at Karhula has led to spalling of the silicon carbide coating, revealing the bare fibers underneath. As a result of this testing, novel oxide-based ceramics are currently under development. During the initial 2046 hours of operation using a variety of coal and sorbent types at the temperature of up to 900°C (1650°F), no ash bridging was observed. However, later testing using a different limestone resulted in ash bridging in the filter vessel.

<u>Filter Element Development</u> In 1994, four projects were initiated by awarding contracts to B&W, Dupont Lanxide Composites, Pall Aeropower, and Westinghouse to develop and test a second generation of damage-tolerant hot-gas filters. Filters developed under this program are expected to be tolerant of thermal stresses and to exhibit non-brittle behavior under mechanical loading. The B&W concept is an alumina-based continuous fiber ceramic composite (CFCC) material incorporating a chopped fiber matrix in a filament-wound continuous fiber structure. Dupont Lanxide Composites are developing their PRD-66 material, which is a unique microcracked oxide material that exhibits thermal shock resistance. Pall Aeropower is building on iron aluminide technology developed at the Oak Ridge National Laboratory to develop a sulfur-tolerant porous metal filter for IGCC applications. Westinghouse, in conjunction with Techniweave, is developing a mullite-based CFCC filter material using a three-dimensional weaving process. CFCC exhibits non-brittle mechanical properties and is resistant to thermal stresses. This filter has been exposed for almost 2000 hours in pilot scale PFBC facilities in Karhula Finland and at Power Systems Development Facility at Wilsonville, AL.

D. INTEGRATED GASIFICATION COMBINED CYCLES (IGCC)

IGCC power plants have the advantages of superior environmental performance, high energy efficiency, and fuel flexibility suitable for repowering or new plant applications. In an IGCC system, coal is gasified at elevated pressures, typically 20 to 30 atm, to produce a fuel gas which is filtered and desulfurized prior to burning in a combustion turbine to produce electricity. High efficiency is provided by the combination of gas and steam turbines, and hot gas cleanup. The hot gas cleanup involves removal of particulates and sulfur, mostly H_2S and some carbonyl sulfide, at the high temperature conditions.

The DOE IGCC program supports the Clean Coal Technology (CCT) demonstration projects and also smaller scale research and development (R&D) projects for long-term improvements.

The CCT program is a government-industry cooperative effort with $6 billion cost, 34% of which is provided by DOE. Currently there are three IGCC demonstration projects under development to reduce technical and financial risks in commercialization of the technology (see Table 2). Wabash River Generating Unit began operation in November 1995, the Tampa Electric Company's Polk Power Station began operation in July 1996, and Sierra Pacific Power Company's Piñon Pine Station began operation in January 1998.

The R&D program focuses on system development and improvements that include mainly hot gas desulfurization and hot gas particulate control to improve the efficiency and cost of the overall system. The cleanup requirements of IGCC systems are much more rigorous than the federally mandated New Source Performance Standards, because downstream equipment such as gas turbines

TABLE 2. IGCC Clean Coal Technology Demonstration Projects

CCT Projects	Size, MW_e	Process	Development Status
Piñon Pine IGCC Power project (Sierra Pacific Power Company)	99	Air-blown KRW agglomerating fluidized bed gasifier with hot gas cleanup	o Operational since January 1998 o First operating plant to use hot-gas cleanup featuring a transport desulfurizer o Capable of gasifying all types of coals
Tampa Electric IGCC Project	250	Texaco oxygen-blown entrained-bed gasifier with hot and cold gas cleanup	o First greenfield IGCC unit in commercial service o Operational since October 1996 o Operated with both coal and petroleum coke o 25-MW_e GE moving-bed desulfurization unit o Low heat rate of 9200 Btu/kWh
Wabash River Coal Gasification Repowering Project	262	Destec's two-stage, oxygen-blown, entrained-flow gasifier with cold gas cleanup	o First repowered IGCC unit in commercial service o World's largest single train IGCC o Operational since November 1995 o Achieved 103% of rated capacity and 95% availability

require very low levels of sulfur and nitrogen compounds, particulates, alkali metals, and chlorine compounds.

Hot-Gas Desulfurization The effort to remove hydrogen sulfide (H_2S) from the gasifier product gas has two distinct thrusts: development of sorbents and reactor designs. Various sorbents have been formulated and tested for several reactor types, including moving-bed, fluidized-bed, and transport or entrained-bed reactors.

Zinc-based sorbents are currently the most well-developed desulfurization sorbents and are near commercialization with vendor warranties.

Research Triangle Institute is developing two candidate sorbents for the Sierra-Pacific plant of CCT program that includes EX-SO3 and MRCH-67. EX-SO3 is a commercially spray-dried sorbent [10]. This is a highly attrition-resistant sorbent with 99.7% sulfur removal from coal gas to 20 ppmv H_2S or less. The sorbent was regenerated at 537°C (1000°F) over 50 cycles with improved reactivity compared to the fresh sorbent. MRCH-67 is a zinc-based sorbent prepared by a proprietary technique in the 40- to 150-micron size range. Its attrition index is below 1% and it has been designed to provide a high removal efficiency at temperatures as low as 450°C. MRCH-61 (a previous form) was tested in a bench scale reactor, demonstrating < 10 ppmv H_2S exit concentration consistently with 60% to 100% capacity utilization prior to breakthrough. Further optimization of sorbent formulation led to the development of MRCH-67.

General Electric Environmental Services, Inc. has developed a moving-bed, high-temperature desulfurization system in Schenectady, NY. A counter-current flow absorber with 5,443 kg (12,000 lb) of a mixed-metal oxide sorbent is employed for removal of H_2S from the fuel gas generated from an air-blown gasifier at a pressure of 20 atm and a nominal temperature of 537°C (1000°F). An external sorbent regeneration loop produces an off stream of SO_2 suitable as feed to a sulfuric acid plant. Over 1000 hours of testing have been completed in the 3-MWe scale unit to investigate the performance and durability of mixed-metal oxide sorbents. Control systems have been developed for automatic control of the integrated gasifier/hot gas desulfurization system. Also, a circulating fluidized bed chloride removal system was installed and operated. Chloride can damage desulfurization sorbents and cause fouling of process piping. Up to 95% chloride removal has been demonstrated using sodium bicarbonate with up to 50% bicarbonate utilization.

DOE Future Program In review of changing market conditions, the DOE future IGCC program has been refocused. The program will be more diversified toward the production of market-based energy and chemical products. A variety of products such as electricity, steam, hydrogen, fuels and chemicals will be produced to provide the maximum benefits to industry (see Figure 6).

II. ENVIRONMENTAL CONTROL TECHNOLOGIES

The U.S. electric utility industry has made considerable progress in reducing SO_2 and particulate emissions even though there has been a large increase in coal consumption. Full implementation of current regulations will result in an annual cap on power plant SO_2 emissions of 8.9 million tons, down from more than 14.5 million tons in 1990. Similarly, reduction in NOx emissions from U.S. utilities has been realized. Particulate emissions from the utility industry in 1990 were less than 450,000 tons (for annual coal use of nearly 775 million tons) as compared with more than 3 million tons/yr in the early 1970s.

SO_2 and NOx Removal Technologies There are a number of commercially available technologies which are capable of reducing NOx and SO_2 emissions to the levels required by current regulations. Table 3 summarizes better-known SO_2 and NOx removal technologies. Commercial SO_2 removal processes are wet scrubber systems based on calcium, sodium or magnesium sorbents. DOE has been developing dry regenerarable sorbent systems to reduce sorbent wastes and also to produce a by-product from SO_2 such as sulfuric acid, elemental sulfur or a sulfate fertilizer. NOx removal technologies are based on combustion modifications that include low NOx burners, overfire air, and reburning. Technologies which destroy NOx downstream of the combustion zone include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).

Particulates ($PM_{2.5}$) Currently, almost all of the nearly 1200 coal-fired power plants in the U.S. are equipped with some type of particulate control technologies. The most popular technology is electrostatic precipitators (ESP) installed on more than 915 of the units, followed by baghouses with nearly 9% of the market. Baghouses and ESPs with removal efficiencies exceeding 99.6% and 99.8%, respectively, are currently available at moderate costs. However, a new fleet of particulate control technologies would be needed with higher efficiencies and with capabilities to capture much finer particles, $PM_{2.5}$ (particulate matter with an aerodynamic diameter equal to or less than 2.5 microns), as required by new standards.

The U.S. Environmental Protection Agency (EPA) has promulgated a new regulation for National Ambient Air Quality Standards controlling particulate matter concentration in the air. $PM_{2.5}$ are thought to be the cause of most of the health and visibility impairment. The new standards establish an annual mean limit of 15 µg/m^3 and a 24-hour limit of 65 µg/m^3 for $PM_{2.5}$.

TABLE 3. Examples of SO_2 and NO_x Control Systems

Technology	Pollutants Removed	Typical Efficiency (%)	Estimated Capital Cost ($/kW)
Wet FGD (LSFO)	SO_2	# 99	130
Wellman-Lord	SO_2	98	380-- 440
MgEL	SO_2	98	215- 240
Spray Dryer	SO_2, Hg, Cl	75-90	140 - 210
Duct Injection	SO_2	50-70	70 - 120
NOXSO	SO_2/NO_x	80-90 (NO_x), 90-99 (SO_2)	280 - 380
Copper Oxide	SO_2/NO_x	90-95 (SO_2) 80-90 (NO_x)	260 - 340
SNRB	SO_2/NO_x/PM	70-90 (SO_2) 90 (NO_x) 99+ (PM)	275 - 365
SNOX	SO_2/NO_x	95 (SO_2) 90 (NO_x)	320 - 470
LNB/OFA	NO_x	35 - 70	10 - 25
Reburn	NO_x	40 - 65	20 - 50
SCR	NO_x	80- 90	50 - 75
SNCR	NO_x	35 - 50	10 - 20

$PM_{2.5}$ may be formed in two manners: They may be directly emitted from the source into the atmosphere (primary emissions) or may be formed as a result of gas or vapor reactions in the atmosphere (secondary emissions). $PM_{2.5}$ tend to be the secondary emissions, resulting from the chemical reaction of gaseous combustion products such as SO_2 and NOx, and their control is a potential issue.

Air Toxics (Mercury) The 1990 Clean Air Act Amendments identified 189 substances that are designated as hazardous air pollutants (air toxics). These substances are chemicals, including heavy metals and organic compounds in both solid and gaseous forms, known to pose a risk to human health. A significant number of the air toxics, at least 37, are known to be emitted from coal combustion systems as a result of their presence as trace elements in coal mineral matter and the various organic compounds formed during the combustion process. However, there is considerable uncertainty in the quantification of toxic emissions from coal-based combustors due to variability of trace element concentrations in coal, variation in design/operation of combustors, etc. One of these elements that is getting much attention due to its quantity and toxicity is mercury.

Mercury emissions to air and releases to water occur both naturally and through human activities. According to the most recent emissions inventory (1994-95), major emitters of mercury to the atmosphere in the United States were electric utilities, municipal waste combustors, commercial and industrial boilers, medical waste incinerators, and chlor-alkali plants. Until the middle of the decade, municipal waste combustors, hazardous waste combustors, and medical waste incinerators were the leading emitting source category but they have recently been regulated by the EPA. The EPA estimates that emissions from municipal waste combustors and medical waste incinerators will decline by 90% from 1990 levels by 2000 as a result of these limits.

Coal-fired utilities are now the leading man-made source of mercury emissions in the U.S. Of the 5,000 tons of global mercury emissions estimated to have been produced in 1994-95, U.S. coal-fired power plants contributed about 51 tons, or 1%. This rate of mercury emissions represented 33% of the 158 tons of mercury released in the U.S. for the same time period. Although coal fired utilities are now the leading source of U.S. anthropogenic emissions, EPA has deferred a determination to regulate these emissions. The EPA Mercury Study Report, published in 1996, indicates that most control technologies for coal-fired boilers are in the research stages, making it difficult to predict final cost effectiveness and time needed to commercialize the technologies.

CO_2 Mitigation One of the recent concerns on burning fossil fuel is generation of CO_2, which is considered as one of the main greenhouse gases. There are basically three technical options for CO_2 mitigation: a) decarbonization that is reducing the carbon intensity of fuels, b) efficiency improvement on combustion processes, and c) CO_2 sequestration.

Decarbonization is the trend that has been underway for the past 100 years. As technology has progressed, society has moved to coal, then oil, and natural gas. On average, using coal, oil, and gas for energy production emits about 200, 180, and 120 lb of CO_2 per million Btu of heat input, respectively. Consequently, natural gas may be favored as it is a less carbon intensive fuel. However, long-term availability of gas reserves and delivered prices are the issues. Other sources are renewable energy, such as hydro and biomass, which already provide nearly 12% of U.S. electricity and more than 20% of world electricity production. Each of these energy sources has its own set of environmental and cost issues.

Improving the combustion/cycle efficiency is a "no regret" way to reduce CO_2 emissions. Advanced technologies can improve the efficiency and contribute to CO_2 emissions reduction. But improving the efficiency alone will not be enough to solve the CO_2 emissions issue over the long term.

Sequestration is the remaining option, that is CO_2 capture, reuse, and disposal. At power plants, CO_2 can be recovered, concentrated and then transported off-site for long term storage. The storage options include: injecting CO_2 into depleted oil and gas wells or saline aquifers; injecting it deep into the ocean; and injecting it into deep, unmineable coal seams. In 1997, the DOE issued a research solicitation for novel concepts for the inexpensive capture, reuse and permanent disposal of greenhouse gases, and selected 12 research projects that ranged from the use of carbon dioxide absorbing-algae to deep-ocean disposal. These research projects will begin exploring whether practical, affordable methods can be developed to prevent greenhouse gases from building up in the atmosphere.

III. CONCLUDING REMARKS

Substantial advances are being made in coal-fired power plant technology for cleaner, more efficient and more affordable plants for the 21st century. LEBS is moving towards commercialization, with ground breaking for LEBS proof-of-concept plant scheduled for the summer of 2000. Engineering development of HIPPS is continuing. A recent successful test of a radiant air heater showing the capability to heat air to 1100^{o}C has demonstrated the basic soundness of the design. Hot gas filter testing has been successful over 2000 hours for advancing PFBC and IGCC technologies to more efficient plants. Furthermore, IGCC is moving toward product diversification, producing both energy and chemical feedstocks.

IV. REFERENCES

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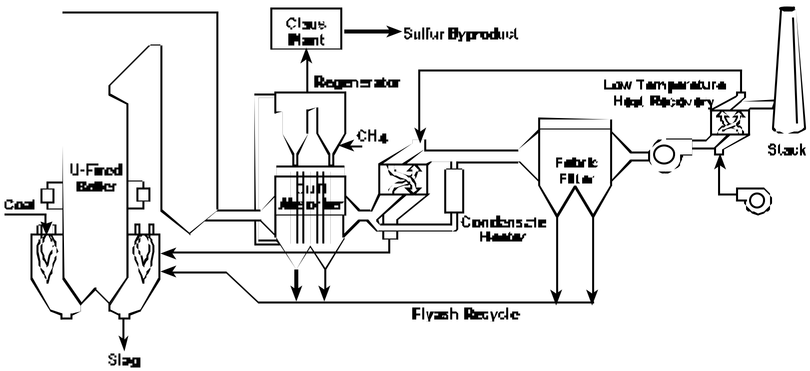

Figure 1. LEBS Commercial Generating Unit (DB Riley)

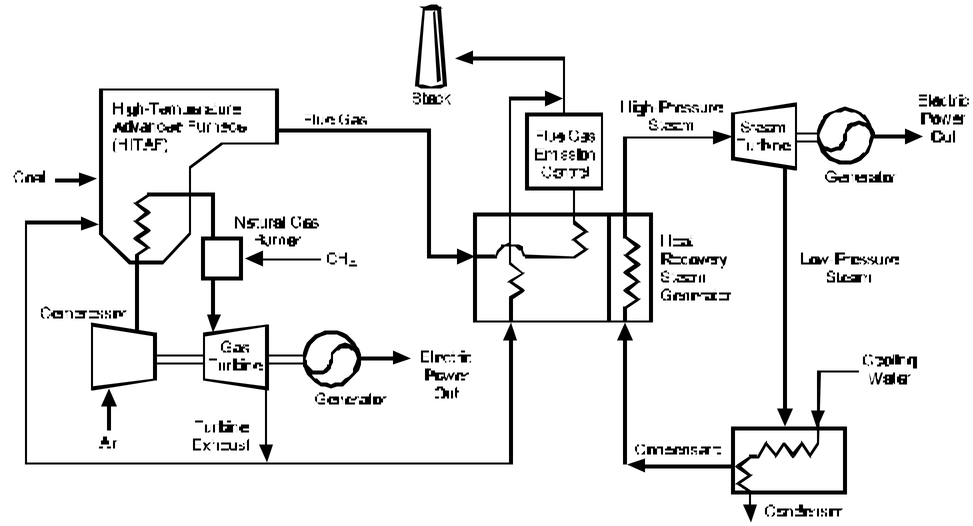

Figure 3. High-Performance Power System

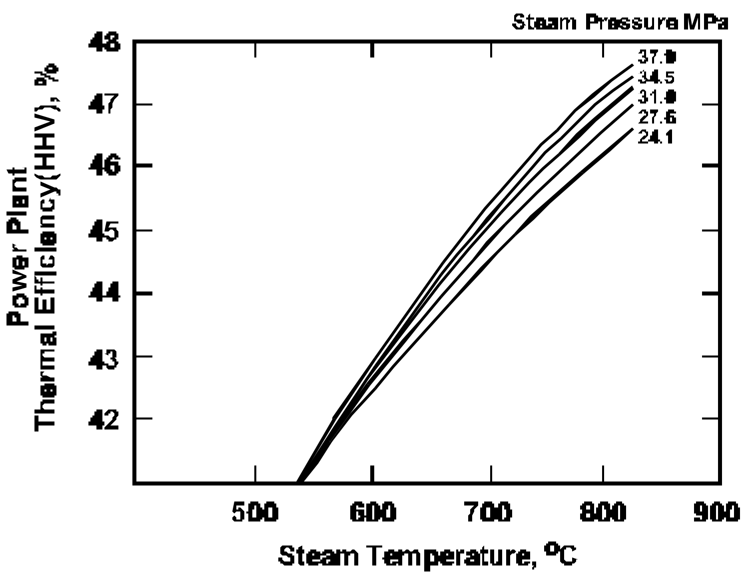

Figure 2. Low Emission Boiler System Efficiency

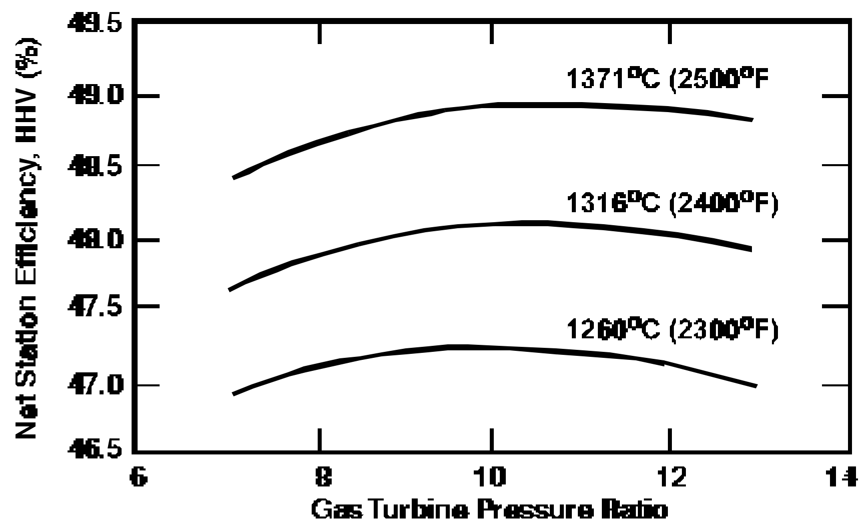

Figure 4. High-Performance Power System Efficiency

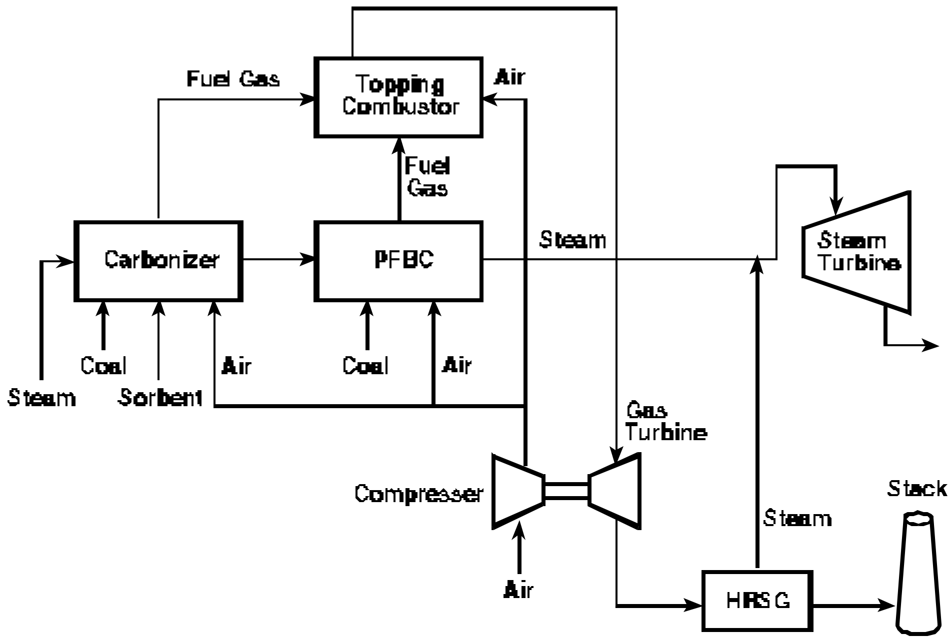

Figure 5. Second Generation PFBC

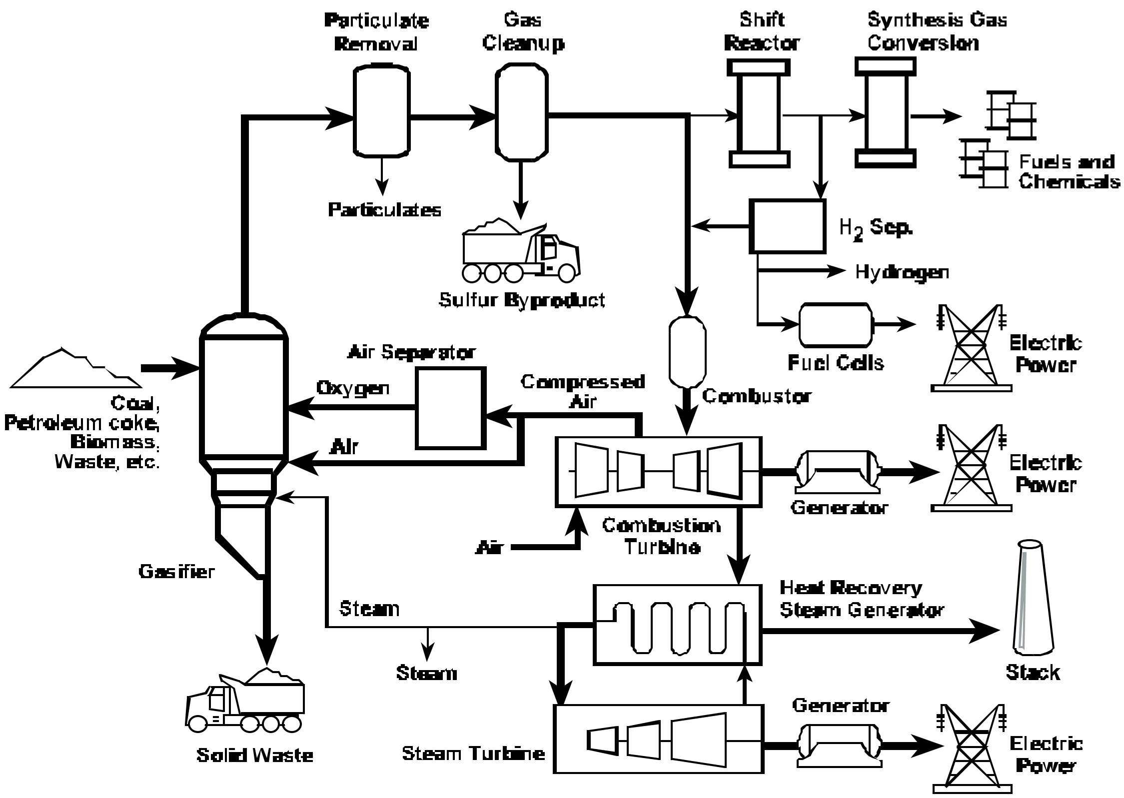

Figure 6. Integrated Gasification Combined Cycle (Technology Options)